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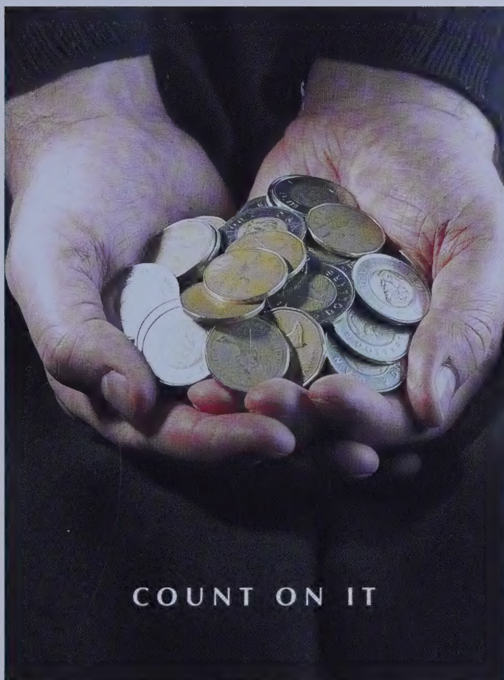


NAV Energy Trust

CORPORATE PROFILE

NAV Energy Trust (NAV) is a Canadian oil and natural gas energy trust based in Calgary, Alberta. NAV was created by way of a Plan of Arrangement, resulting in a reorganization into a trust and an exploration entity. The reorganization was effective on December 29, 2003. NAV began with production of approximately 5,100 boe per day and was structured with internalized management.

NAV's strategy is to grow through value-added acquisitions while maintaining production at existing properties through development and exploitation. These internal opportunities will be on high-working-interest, operated properties, mainly at two core areas in Alberta and one in Saskatchewan. NAV's distribution policy is to retain 25-30 percent of annual cash flow for reinvestment into internal opportunities. Acquisitions are funded through the issuance of new units. Since launch, NAV has closed two significant acquisitions totalling $58 million, increasing the Trust's production, reserves, cash flow and net asset value. NAV's management does not receive transaction fees.

NAV's distributions were $0.15 per unit per month during Q1 2004. NAV trades on the Toronto Stock Exchange (TSX) under the symbol NVG.UN. At March 23, 2004 there were 18.8 million trust units and 0.8 million exchangeable shares issued and outstanding.

ANNUAL GENERAL MEETING

The Annual General Meeting of unithholders will be held at 3:00 p.m. on Thursday, May 27, 2004 at the Metropolitan Centre, 333–4th Avenue S.W., Calgary, Alberta, Canada. Unitholders who are unable to attend this meeting are requested to complete and return their proxies to Computershare Investor Services.

IN 2003, NAVIGO CONVERTED TO AN ENERGY TRUST.

[WHY?] Throughout 2003, Navigo's management and board of directors focused on how to maximize shareholder value. They found that Navigo's base of mature producing properties was suited to trust conversion. They also knew that trust conversion usually results in higher valuations for a given asset base. Therefore NAV Energy Trust was created to tap the full cash flow generating potential of the producing assets while maximizing their value in the capital markets. Navigo's higher-risk prospects were, at the same time, placed in a new exploration company. This provides shareholders with exposure to higher-impact upside while protecting NAV's unitholders against excessive capital risk and maximizing cash flow available for distribution.

How will NAV Energy Trust compete?

Experienced management and board

NAV has been launched with a management team and board of directors who have the full range of technical, governance, financial and transactional skill-sets needed to successfully manage and accretively grow a modern energy trust.

Growth through acquisitions

Within two months of converting to a trust, NAV closed two significant acquisitions that grew production by more than 40 percent and reserves by 64 percent, and reduced unit operating and general and administrative costs. NAV is positioned in regions where it is anticipated that significant additional dispositions by other operators will occur, creating opportunity for further accretive acquisitions.

Operate in areas where trusts are less active

In 2003, approximately 60 percent of NAV's production came from two core areas in northern and central Alberta, plus southeast Saskatchewan. Northern Alberta, in particular, is not a traditional energy trust operating area. The reduced buyer-competition and NAV's expertise operating in these areas create a significant competitive advantage for NAV.

Use significant tax pools to minimize taxation of current distributions

Currently 85-90 percent of NAV's monthly distributions flow to unitholders free of income tax. This is due to the large tax pools built up under Navigo. These tax pools should be sufficient to maintain a low level of taxability in the current year.

Key Events

Through to September 2003	October 2003	December 2003	January 2004	February 2004	March 2004
Navigo's management and board consider options to maximize shareholder value. Navigo builds up development drilling inventory to benefit possible trust operations.	Navigo's management and board announce that Navigo proposes to convert to an energy trust, with higher-risk exploration opportunities placed into a separate exploration company.	On December 17, Navigo's shareholders approve conversion to an energy trust. Plan of Arrangement closes on December 29, with Navigo shareholders receiving three-for-one consolidated units in NAV and common shares in C1 Energy Ltd.	On January 6, NAV begins trading on the Toronto Stock Exchange, opening at $10.40 per unit. On January 28, NAV closes a $57.5 million financing, using the funds for a $36 million acquisition at Wapella, in southeast Saskatchewan. This adds 1,350 barrels per day of production and 4.4 million barrels of reserves. Remaining funds were used to reduce debt and fund development activities.	On February 26, NAV closes a $21.8 million acquisition of privately-held Java Energy Inc., adding 700 boe per day of production and 1.7 million barrels of reserves. The production is split approximately 60 percent natural gas and 40 percent crude oil, plus undeveloped lands with natural gas development potential, adjacent to existing NAV natural gas production.	Completion of the winter drilling program of 17, 100 percent working interest shallow gas wells in the Black and Sousa fields, the tie-in of a 100 percent working interest deep gas well in the Fire field, plus the completion of two 40 percent working interest Keg River oil wells in the Zama field.

OPERATING HIGHLIGHTS

Twelve months ended December 31	2003	2002	% Change
DAILY PRODUCTION			
Crude oil and NGLs (bbls/d)	2,951	4,032	(27)
Natural gas (mcf/d)	16,608	19,674	(16)
Oil equivalent (boe/d @ 6:1)	5,719	7,311	(22)
AVERAGE WELLHEAD PRICES			
Crude oil and NGLs ($/bbl)	40.40	36.33	11
Crude oil hedging ($/bbl)	(2.78)	(4.76)	–
Natural gas ($/mcf)	6.46	3.86	67
Natural gas hedging ($/mcf)	(0.04)	0.12	–
Oil equivalent after hedging ($/boe)	38.13	28.24	35

FINANCIAL HIGHLIGHTS

($000's except unit and per unit amounts)	2003	2002	% Change
Production revenue after hedging	79,591	75,373	6
Cash flow from operations	28,448	28,306	1
Per unit – basic	2.43	2.59	(6)
– diluted	2.43	2.59	(6)
Net income (loss)	360	(269)	234
Per unit – basic	0.03	(0.02)	250
– diluted	0.03	(0.02)	250
Bank debt	36,059	26,573	36
Working capital deficiency	8,805	9,033	(3)
Net debt	44,864	35,606	26
Capital expenditures	42,132	37,885	11
TRUST UNITS (000s)			
Weighted average – basic	11,694	10,905	7
Weighted average – diluted	11,714	10,941	7
Total outstanding	12,192	11,683	4

For per unit comparison purposes, the number of shares for 2002 have been converted on a three-for-one basis.

TOM STAN, President & Chief Executive Officer (seated)

From left:

RON BARMBY, Vice President & Chief Operating Officer

ROB D'ADAMO, Vice President, Business Development & Land

JANALEE SHUTIAK, Vice President & Chief Financial Officer

LETTER TO UNITHOLDERS

NAV has hit the ground running. Three months after our conversion of Navigo Energy Inc. (Navigo), NAV has closed two significant acquisitions totalling $58 million, representing nearly half our market capitalization. The trust conversion has clearly been accepted by the capital markets, with our units opening at $10.40 in early January and holding reasonably steady since then. We have individual and institutional unitholders all over North America, and our trading volume has been high, creating good liquidity. To date we have declared three monthly distributions of $0.15 per unit each. Our reserves picture under Canada's new, strengthened standards is very solid. We have excellent development opportunities to maintain production levels internally and we are strategically positioned to continue growing through accretive acquisitions.

Transforming Navigo Energy Inc. into NAV Energy Trust

Last year, Navigo's senior management and board of directors examined various options to maximize shareholder value. Navigo's asset portfolio consisted of mature producing properties plus several promising exploration plays. But the Navigo management and board did not want to dilute shareholders' equity and increase their risk burden by committing major capital to high-risk exploration. We concluded the best path forward was conversion of most of the asset base into an energy trust, resulting in higher valuations in the capital markets. A newly formed exploration company would take the higher-risk plays. The two components, a trust and an exploration company, would then provide Navigo shareholders with a steady return on one hand and exposure to higher-impact activity on the other.

During this period Navigo's management fine-tuned the asset portfolio to the needs of an energy trust. Inventories of low-risk development opportunities were built up at Rainbow-Zama-Sousa, Black, Strathmore and Macoun, while drilling was focused on converting proven undeveloped reserves to proved producing.

The reorganization was announced in October, approved by shareholders on December 17 and closed on December 29. For every three Navigo common shares shareholders received one NAV unit plus one common share in the newly formed C1 Energy Ltd. (C1). NAV received Navigo's mature properties, which were producing a combined 5,100 boe per day at year-end. NAV's management team was a continuation from Navigo and does not receive any management, acquisition or disposition fees. This arrangement increases cash available for distribution and aligns the interests of NAV's management with those of unitholders. NAV Energy Trust began trading on the Toronto Stock Exchange on January 6, 2004.

C1 is a separate exploration and development company with its own management team and board of directors. C1 trades on the Toronto Stock Exchange. It received the exploration play at the Gift Lake Metis Settlement plus 60 percent of the Seal property. Under an administrative agreement the two companies are sharing office space and technical personnel for the short term.

How NAV Can Profit in Today's Western Canada Sedimentary Basin

Strategically, the management and board of NAV believe the Western Canada Sedimentary Basin's evolution will continue to favour the growth of energy trusts. The Basin's large, historical explorers have realized their future growth depends on re-deploying internationally, to the frontiers or into Alberta's oil sands. The stronger Canadian dollar is encouraging U.S. producers to de-emphasize Canada. Dozens of emerging and junior companies are taking on the mantle of higher-risk exploration, their management intent on timely monetization. These developments make the Basin friendly to royalty trusts, and we believe the bulk of its conventional production will eventually come from our sector.

NAV has a strong position on this landscape. Our largest core area is in northern Alberta in a region where there is little other trust activity. This should reduce buyer competition for future assets, creating a competitive advantage for NAV and increasing the accretiveness of future acquisitions. Our research suggests assets producing a combined 80,000 boe per day could come into play in this core area.

Hitting the Ground Running

NAV closed two significant acquisitions in the first two months of 2004. The first was a $36 million property purchase that closed on January 28, 2004, adding approximately 1,350 barrels per day of medium-gravity crude oil production at Wapella, Saskatchewan. The high-working-interest property has a reserve-life-index of greater than eight years and offers significant potential to add production and reserves through waterflood, a low-risk secondary recovery technique. The previous operator conducted a pilot project confirming waterflood feasibility. NAV has initiated full-scale engineering planning, and intends to launch field development of the waterflood in Q3 2004.

The second transaction was the $21.8 million acquisition of privately held Java Energy Inc. (Java). The deal closed on February 26, 2004, initially adding 700 boe in daily volumes, 60 percent of which is natural gas. Java's principal asset lies adjacent to NAV's Black field, which taps the same Bluesky-Gething natural gas trend, creating opportunities for economies of scale and technical efficiencies. The combined properties have strong upside potential. In winter 2003/2004, Navigo drilled 17 successful Bluesky-Gething shallow gas wells and Java drilled 16, one of which was dry. NAV now has an inventory of 40 additional locations on the combined property targeting Bluesky-Gething gas. This formation yields long-life, low-decline wells, a good production profile for an energy trust.

The transactions were funded through a $57.5 million offering of units that closed in late January 2004 at $10 per unit and an issue of exchangeable shares on the Java acquisition. Combined, the acquisitions increased NAV's daily production by over 40 percent, proved plus probable reserves by over 60 percent and the corporate reserve-life-index to over six years on a proven and probable basis or by 25 percent, while reducing NAV's operating costs and general and administrative costs per unit of production.

Reserves

Reserves are crucial to the future health, unit value and distributions of an energy trust. NAV's oil and gas reserves as of December 31, 2003 have been evaluated by Gilbert Laustsen Jung Associates Ltd. (GLJ) who have been our independent reserve evaluators since 2001. The GLJ evaluation has been prepared in accordance with National Instrument (NI) 51-101, the new standards of disclosure for oil and gas activities as mandated by the Canadian Securities Administrators for year ends beginning with December 31, 2003.

Subsequent to year end, we closed both the Wapella property acquisition and Java acquisition. The two acquisitions added 64 percent to our reserve base and 40 percent to our production base, significantly strengthening NAV. As at February 29, 2004, on a 6:1 conversion basis and under NI 51-101, our proved producing reserves were 8.0 mmboe, total proved reserves were 10.9 mmboe, and total proved and probable reserves were 14.7 mmboe. As a percentage our proved producing reserves are 74 percent of total proved reserves.

Going Forward

Any energy trust has two basic options; it can maximize short-term distributions by paying out nearly all cash flow, simultaneously repaying unitholders' capital and depleting reserves in a controlled "blow-down" scenario; or, it can grow. NAV is part of the new breed of active trusts that employs robust capital programs to maximize reserves and production from existing assets, while seeking suitable acquisitions for accretive growth.

Currently NAV has an internal development inventory representing approximately $50 million worth of drilling and optimization opportunities to add significant production and reserves. Our inventory will support three to four years of activity and should enable NAV to hold overall production from existing assets at or near the current rate. For 2004 we have an active drilling program planned at Rainbow/Zama/Sousa/Black, targeting a mix of Bluesky-Gething gas and Keg River oil, with higher-risk exploration prospects farmed out to C1, plus the new Wapella waterflood and smaller programs at other properties. Internal development will be largely funded by retention and reinvestment of 25-30 percent of cash flow.

Going forward, NAV's growth will be driven by quality acquisitions, focusing particularly on our existing operating areas. Acquisitions will have the primary aim of maintaining stable distributions per unit, and will be financed primarily through new equity. Our debt policy is to maintain conservative leverage, because commodity prices are volatile, and because debt-servicing diverts cash flow. At year-end 2003, NAV's net debt was $45 million.

An important advantage of NAV is that distributions are expected to be 85-90 percent non-taxable for the current year, thanks to the large tax pools built up by Navigo.

The Human Component

An investor committing capital to any company is essentially buying management's ability to execute its strategy to create shareholder value. Senior management, including the President and C.E.O., consist of very experienced industry veterans who span the full range of technical, financial and transactional skills required by an energy trust.

Success will come from a combination of strategy, leadership and implementation. Implementation can only happen through a solid team of field and head office personnel who believe in the strategy and do everything they can to make it happen. NAV's employees have been successful in sustaining high performance through a period of intense change. This included the crucial conversion period, which took place through the past Christmas and New Year's holidays. Our deepest thanks go to all employees.

Our thanks also go to NAV's Board of Directors. The Board includes a number of directors of the prior Navigo board, providing continuity as NAV implements its growth strategy. The board consists of individuals who are strongly focused on ethical governance, reserves integrity, technical excellence in operations and strong financial control.

On behalf of the Board of Directors,

Tom Stan
President & Chief Executive Officer
March 24, 2004

OPERATIONS REVIEW

NAV owns and operates assets in three core areas: the Northern Region encompassing the Rainbow, Zama, Sousa and Black properties, the South-Central Alberta Region where the main properties are Strathmore, Cache-Clay, Viking-Kinsella, Hobbema and newly acquired Heart Lake and Twinning properties and the Southeastern Saskatchewan Region comprised of the Macoun property together with the recently acquired Wapella and Benson properties. NAV Energy Trust entered 2004 with combined production of 5,100 boe per day, of which there was a 50/50 split of natural gas and crude oil.

Navigo's capital expenditures in 2003 totalled $42.1 million, funding new wells plus field optimization. The 2003 program reduced Navigo's annual production decline from an estimated 29 percent with no investment to 11 percent.

Operating costs averaged $10.37 per boe in 2003, a rate NAV intends to reduce through a number of initiatives. Infill Bluesky-Gething gas drilling at Black is expected to double production thereby reducing unit costs. In Q1 2004, increased oil volumes from Zama due to the successful two well farmout to C1, and the tie-in of a significant Fire gas well, will also assist in reducing unit lifting costs. At Strathmore, where low well-productivity generates high unit costs, horizontal wells will be drilled to more effectively exploit the formation and reduce unit costs.

In January 2004 NAV made a $36 million property acquisition at Wapella in southeastern Saskatchewan, adding production of approximately 1,350 barrels per day of medium-gravity crude. The property contained 4.4 million barrels of proved plus probable reserves at January 31, 2004, yielding a reserve-life-index of 8.9 years. Combined with existing southeastern Saskatchewan assets at Macoun, the two form the Trust's third core area.

In February 2004 NAV acquired privately owned Java Energy Inc. for $21.8 million, adding production of 700 boe per day, 60 percent of which is natural gas. Java's main asset lies adjacent to Black and produces from the same Bluesky-Gething natural gas trend. The Java assets contained 1.7 million boe of proved plus probable reserves at February 29, 2004, yielding a reserve-life-index of 6.6 years.

The two acquisitions plus incremental production from NAV's winter drilling program will increase NAV's total production to approximately 7,000 boe per day in the second quarter of 2004.

Working with our stakeholders

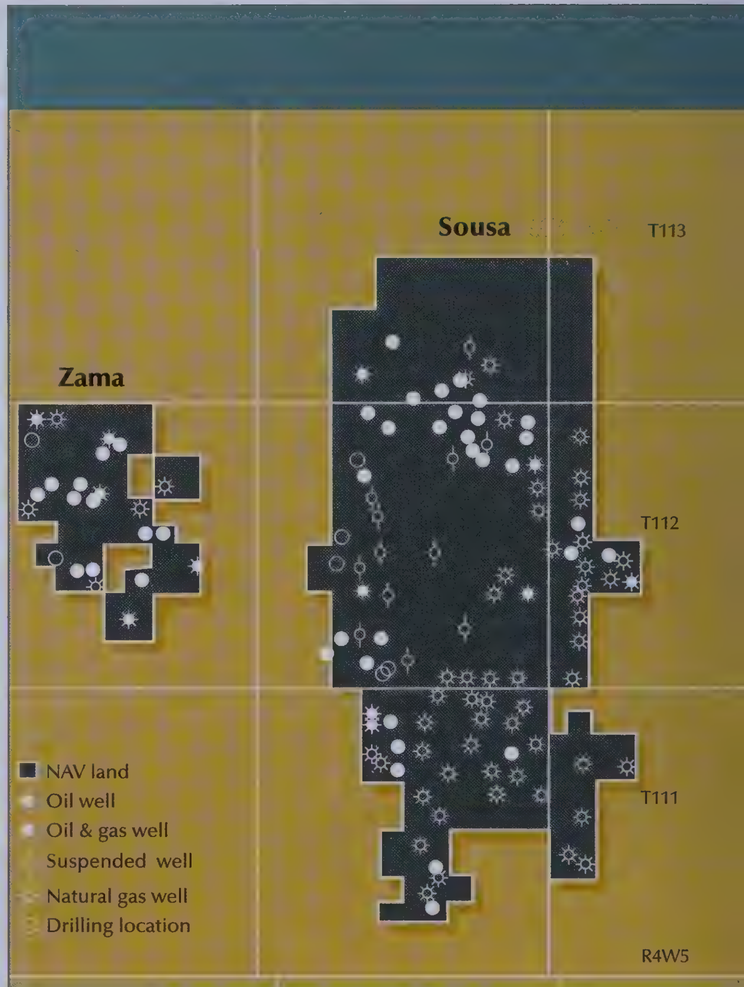
NAV is more than just barrels and cubic feet: we are environmentally focused.

In Q1 2004, in recognition of its custodianship of the environment and its operational practices, Navigo Energy Inc. was nominated for the province's Emerald Award by the Dene Tha' First Nation, the Alberta Wilderness Association, and Alberta Park and Protected Areas. The award is conferred by the Alberta Emerald Foundation for Environmental Excellence and recognizes outstanding environmental leadership in Alberta.

Northern Region

The NAV-operated Northern Region where NAV has an average 90 percent working interest currently produces the largest share of the Trust's production. It has four main properties: Zama, Sousa, Rainbow and Black. In 2003 production averaged 3,427 boe per day, consisting of 8.6 mmcf per day of natural gas from the Bluesky-Gething and Slave Point formations and 1,988 barrels per day of oil from Keg River reefs.

NAV's ongoing focus in the Northern Region is to offset natural production declines through infill natural gas drilling and 3-D seismic based horizontal drilling targeting missed oil pay. Increased volumes anticipated in 2004 should reduce unit operating costs.



Zama/Sousa

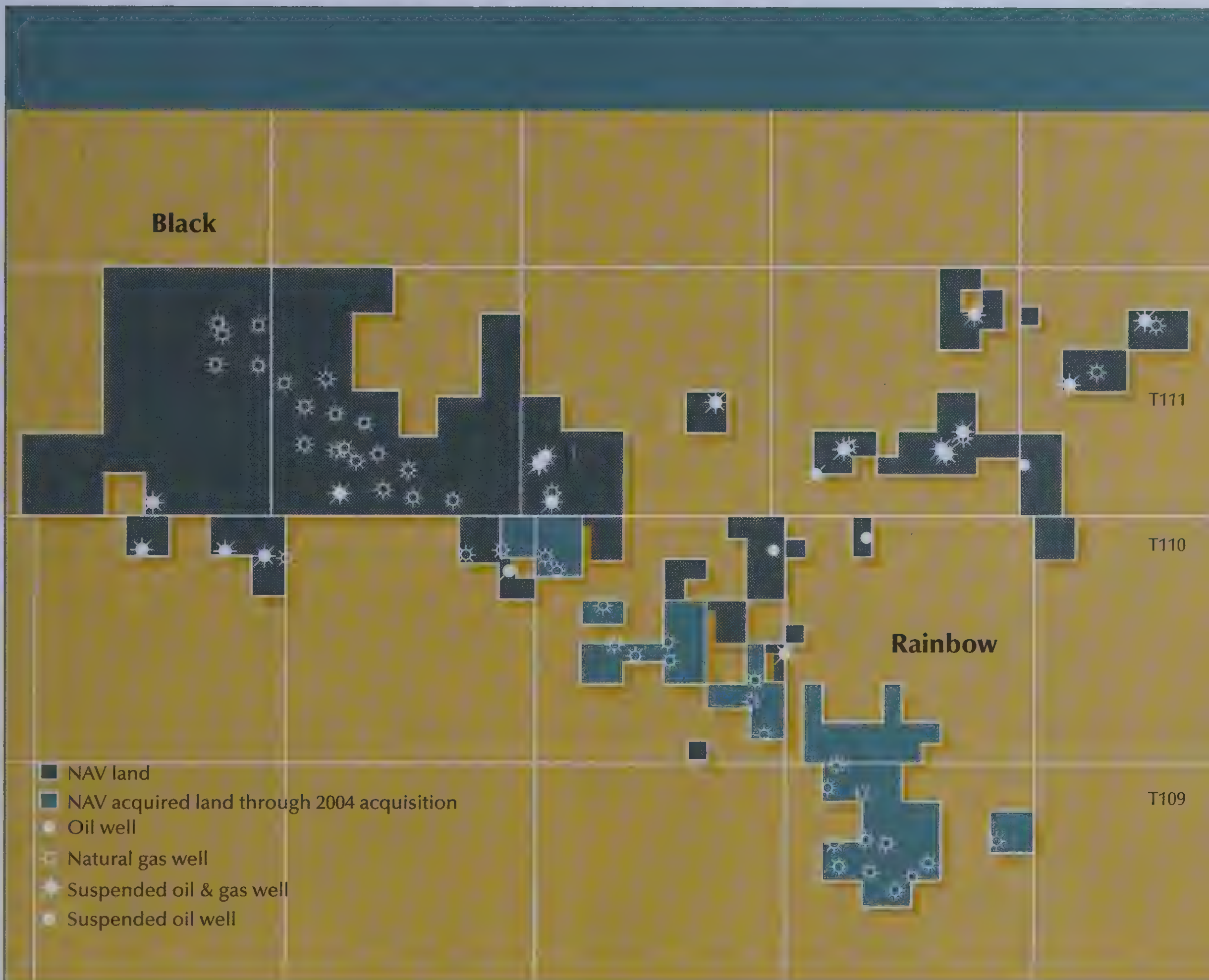
Production from Zama/Sousa, the Trust's largest properties, averaged 2,617 boe per day in 2003, consisting of 1,450 barrels per day of oil and 7.0 mmcf per day of natural gas. Operating costs averaged $10.00 per barrel of Keg River oil and $4.50 per boe of Bluesky-Gething natural gas.

In late 2003 NAV farmed out two wells at Zama-Sousa with an option for a third to C1 Energy Ltd. NAV can elect at casing point to participate for 40 percent in the wells. NAV elected on the first two wells that were drilled in January and February, 2004, and were put on production in late March. It is expected that these wells will contribute 100 – 200 barrels per day net from the Keg River zone.

In late Q1 2004 and into early Q2 2004, a $1.5 million recompletion and tie-in of Sulphur Point production at Fire (in the Zama area) is expected to add 2.0 mmcf per day of natural gas. An $800,000, 2-well Bluesky-Gething program at Sousa should add 0.4 mmcf per day of new gas volumes. NAV's processing facilities, the Sousa gas plant and Sousa oil battery, have ample capacity for the realized and expected incremental volumes.

Rainbow/Black

Rainbow and Black averaged 810 boe per day from a combined 542 barrels per day of oil and 1.6 mmcf per day of natural gas in 2003. Unit operating costs at Rainbow were similar to those at Zama/Sousa. Using



3-D seismic, Navigo in Q3 2003 re-drilled a horizontal leg of Rainbow well 13-6, placed optimally in the original Keg River bank reef target. This added 150 boe per day in new volumes.

A 15-well Bluesky-Gething infill drilling program in Q1 2004 is expected to add 1.5 mmcf per day at a capital cost of $4.75 million, reducing the average operating cost to approximately $8.00 per boe. The Black Field has a further 20 locations which are scheduled to be drilled in 2005. The Rainbow area acquired through the Java acquisition, which is on the same Bluesky-Gething trend as Black, also had a 16 well infill program which was drilled in early 2004. There are 20 additional locations at the Rainbow Field that are scheduled for 2005.

Other Northern Region properties

NAV has an average 40 percent working interest and operates properties at Seal. Net production in Q1 2004 averaged 100 barrels per day of Slave Point oil and 250 mcf per day of non-associated Mississippian gas.

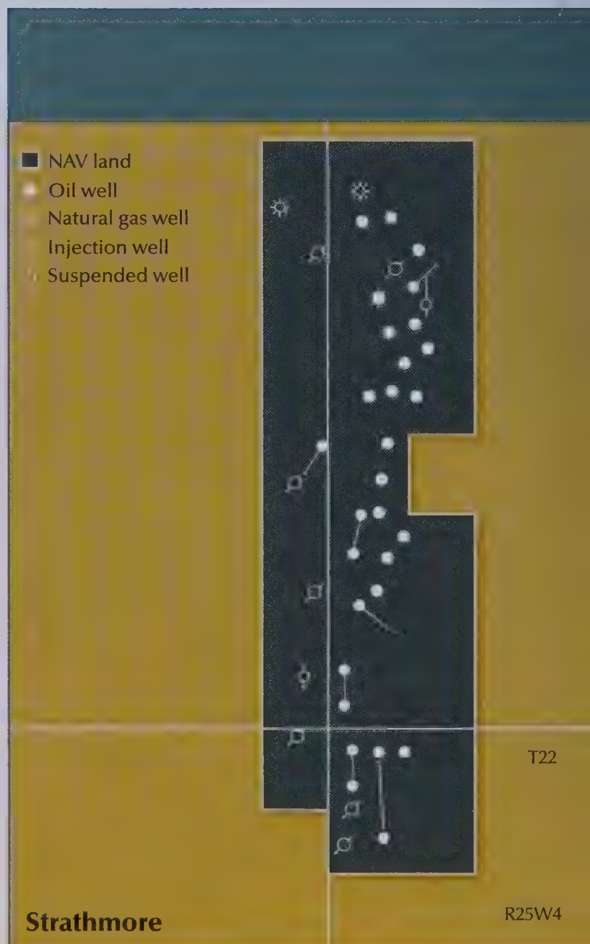
South-Central Alberta Region

NAV's South-Central Alberta Region has six properties: Strathmore, Cache-Clay, Viking-Kinsella, Hobbema and the recently acquired Heart Lake and Twinning through the Java acquisition. In 2003, the core area excluding the recent acquisition produced an average of 1,535 boe per day in 2003, consisting of 390 barrels per day of oil and 6.9 mmcf per day of natural gas, including small volumes from minor, non-operated properties.

Strathmore

Strathmore holds upside potential and was the focus of significant field activity in 2003. Production averaged 258 barrels per day of oil and 1.2 mmcf per day of natural gas.

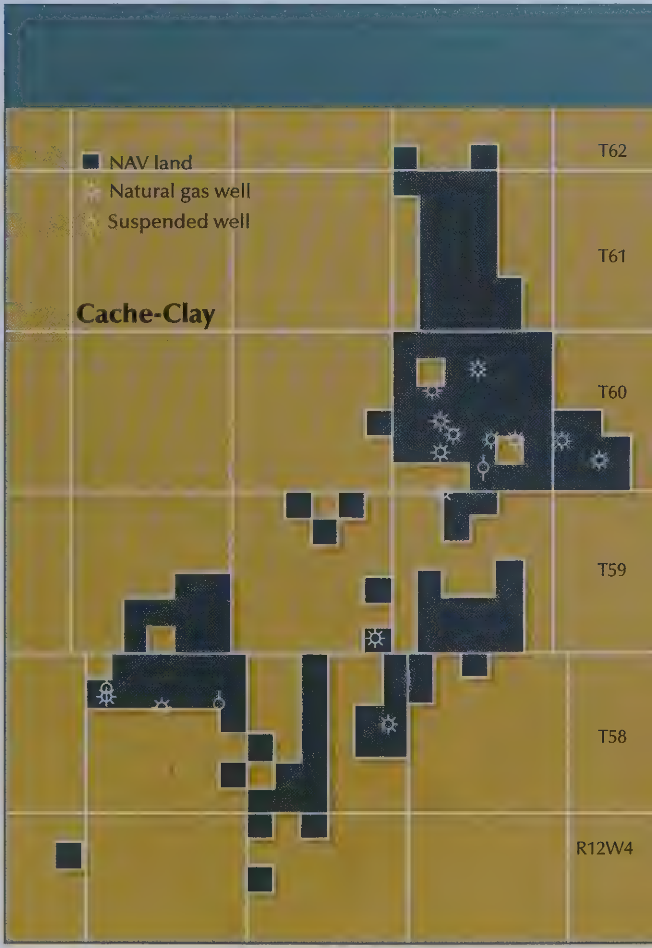
The Lower Manville "B", on waterflood since 1990, has not delivered the incremental production originally forecast. Navigo in Q3 2003 drilled a horizontal pilot well cross-channel in the Lower Mannville. Previous horizontal wells followed the channel axis. The pilot horizontal well at Strathmore encountered down hole caving in the open hole section and as a result must be re-drilled. Although the well has been suspended, it was successful in accessing previously undrained oil reserves while providing strong encouragement to proceed with a field redevelopment plan utilizing a series of new horizontal wells. NAV plans two more,



cross-channel horizontal wells at Strathmore in Q3 2004 to confirm test results which could add an estimated 400 barrels per day of incremental production. If successful, these wells could initiate a redevelopment program of up to 15 wells.

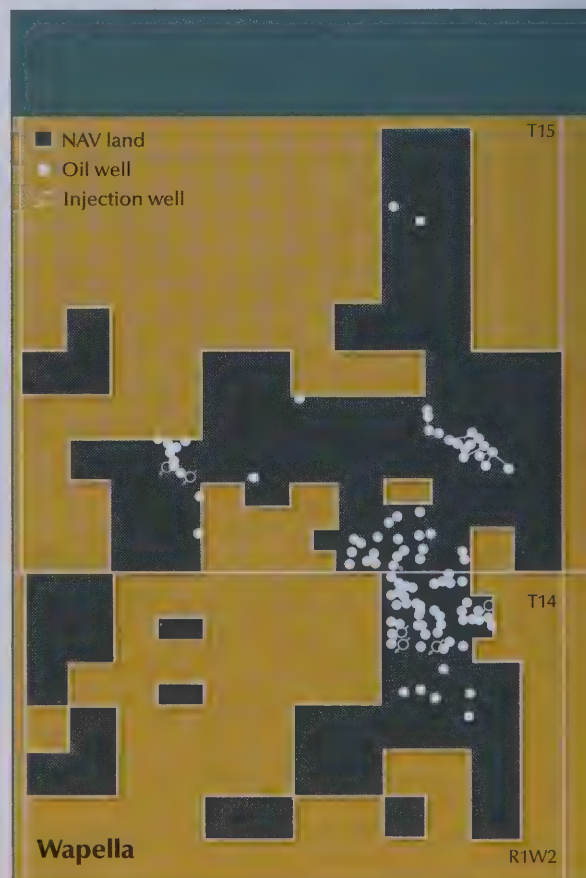
Cache-Clay/Viking-Kinsella and Hobbema

Production from these areas averaged 5.6 mmcf per day and 133 barrels per day or 1,072 boe per day net to NAV. The Trust operates Viking-Kinsella and has a 50 percent working interest, while it also has a 50 percent non-operated interest in both the Cache-Clay and Hobbema areas. Operating costs averaged $6.52 per boe for these areas.



Southeastern Saskatchewan Region

With the acquisition of the Wapella property in January 2004, NAV established a new core area: Southeastern Saskatchewan. The acquisition of Java Energy Inc. in February added additional smaller volumes of medium-gravity crude at Macoun/Benson in Saskatchewan. Combined production in southeastern Saskatchewan from the two acquisitions, plus NAV's existing property, will realize 1,800 barrels per day in March 2004.



Wapella Acquisition

Averaging 1,350 barrels per day of 25 degree API oil from the Shaunavon sands, Wapella responded successfully to a pilot waterflood in 2003 under the previous operator. In 2004, NAV has launched an engineering study for the full field waterflood of the 100-percent-owned property.

Original oil-in-place in the Wapella pool is estimated at 43 million barrels, of which 10 percent has been recovered to date. Based on pilot results, this could

increase the pool's recovery factor by an additional 10 percentage points, adding 4 million barrels in recoverable reserves. Production is expected to peak at 2,000 barrels per day in 2005. Operating costs are currently $6.50 per barrel.

Macoun/Benson

Macoun averaged 210 barrels per day in 2003; operating costs were $10.79 per barrel. A Winnipegosis reef, Macoun resembles the Trust's Keg River pools at Zama. NAV believes that application of accurately placed horizontal wells could achieve similar production gains. A horizontal well defined by 3-D seismic is planned for Q3 2004.

The properties acquired with the Java transaction are producing an average of 150 barrels per day of light-gravity crude in Q1 2004.

2003 STATISTICAL SUMMARY

(This information does not include the Wapella property and Java acquisitions completed in the first quarter of 2004.)

DRILLING ACTIVITY FOR 2003 (NUMBER OF WELLS)

	Exploration		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	4.0	3.0	6.0	6.0	10.0	9.0
Natural gas	5.0	4.6	7.0	6.3	12.0	10.9
Dry	10.0	8.0	–	–	10.0	8.0
Total	19.0	15.6	13.0	12.3	32.0	27.9
Success ratio (%)	47%	49%	100%	100%	69%	71%

PETROLEUM AND NATURAL GAS RESERVES

As at December 31, 2003	Crude oil and NGLs (mbbls)	Natural gas (mmcf)	Oil equivalent (mboe @ 6:1)
Proved producing	2,237	14,962	4,731
Proved non-producing/proved undeveloped	931	5,397	1,830
Total proved	3,167	20,359	6,560
Probable	926	8,851	2,403
Proved plus probable	4,095	29,210	8,963

Note: Columns in table may not total due to rounding.

PRESENT VALUE OF FUTURE CASH FLOWS (BEFORE TAX)

As at December 31, 2003 ($000s)	0%	5%	10%	15%	20%
Proved producing	47,686	45,111	42,610	40,315	38,252
Proved non-producing/ proved undeveloped	20,519	16,399	13,361	11,068	9,299
Total proved	68,205	61,510	55,971	51,383	47,551
Probable	33,604	24,448	18,444	14,365	11,495
Proved plus probable	101,809	85,958	74,415	65,748	59,046

RESERVES PRICE FORECASTS (GLJ)

	WTI ($US/bbl)	Exchange rate ($US/$Cdn)	Light, sweet Edmonton crude ($Cdn/bbl)	AECO-C spot gas ($Cdn/mmbtu)	Edmonton propane ($Cdn/bbl)	Edmonton butane ($Cdn/bbl)	Edmonton pentanes plus ($Cdn/bbl)
2004	34.25	0.75	44.75	6.65	33.75	36.75	45.25
2005	29.00	0.75	37.75	5.55	25.75	28.75	38.25
2006	27.00	0.75	35.25	5.20	23.25	25.25	35.75
2007	25.00	0.75	32.50	5.00	20.50	22.50	33.00

RESERVES RECONCILIATION

	Crude oil and NGLs (mbbls)			Natural gas (bcf)		
	Proved	Probable	Total	Proved	Probable	Total
December 31, 2002	4,950	1,762	6,712	28.8	7.3	36.1
Additions/Revisions	(469)	(670)	(1,139)	(1.8)	1.6	(0.2)
Dispositions	(232)	(165)	(397)	(0.8)	(0.1)	(0.8)
Production	(1,081)	–	(1,081)	(5.9)	–	(5.9)
December 31, 2003	3,167	926	4,095	20.4	8.9	29.2

Note: The above reconciliation of proved and probable reserves includes prior year probable reserve evaluated using National Policy Instrument 2-B definitions adjusted for risk (50 percent factor). Columns in table may not total due to rounding.

RESERVE LIFE INDEX

		Reserve Life Index (years)	
As at January 1, 2004	December daily production	Proved	Proved plus Probable
Oil plus NGLs (bbls/d)	2,805	3.1	4.0
Natural gas (mcf/d)	13,528	4.1	5.9
Oil equivalent (boe/d)	5,060	3.6	4.9

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis of financial and operating results includes information to March 23, 2004 and should be read in conjunction with the consolidated financial statements of NAV Energy Trust (the Trust) contained in this annual report. Per share information for 2002 is based on a conversion of 3:1 to be comparable to the Trust units outstanding at December 31, 2003. Per barrel of oil equivalent (boe) amounts have been calculated using a conversion rate of 6,000 cubic feet of natural gas to one barrel of oil.

Management uses cash flow from operations (cash flow from operating activities before changes in non-cash working capital) to analyze operating performance and leverage and to provide investors with information on potential cash distributions. Cash flow from operations as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow from operations as presented is not intended to represent operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP.

Forward-Looking Statements

Certain statements in this report are forward-looking statements. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable by the Trust at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors, many of which are beyond the control of the Trust. There is no representation by the Trust that actual results achieved during the forecast period will be the same in whole or in part as forecast.

Reorganization Under Plan of Arrangement

NAV Energy Trust was established on November 12, 2003 in connection with a Plan of Arrangement (the Plan of Arrangement) involving the Trust, Navigo Energy Inc. (the Company) and C1 Energy Ltd. (C1 Energy), which was completed on December 29, 2003. Under the Plan of Arrangement the Company transferred to C1 Energy a portion of its producing and exploratory oil and natural gas assets and related site restoration and abandonment for a net book value of $18.1 million. For each three common shares of the Company, shareholders received either one unit of the Trust and one common share of C1 Energy, or one exchangeable share, exchangeable initially into one Trust unit and one common share of C1 Energy. The Trust is an open-end, unincorporated investment trust created under the laws of Alberta pursuant to a Trust Indenture dated November 12, 2003. The Company is a subsidiary of the Trust.

The consolidated financial statements for the Trust at December 31, 2003 are reported on a "continuity of interests" basis which recognizes the Trust as the successor entity to the Company. As such, the consolidated financial statements reflect the full operations and assets of the Company, its subsidiaries and partnership for the 362 days prior to the implementation of the Plan of Arrangement, and the remaining operations and assets of the Trust for the three days from December 29, 2003 to December 31, 2003. The comparative figures are the 2002 consolidated results of the Company.

PRODUCTION

AVERAGE DAILY PRODUCTION

Years ended December 31	**2003**	2002	% Change
Crude oil & NGLs (bbls/d)	**2,951**	4,032	(27)
Natural gas (mmcf/d)	**16.6**	19.7	(16)
Oil equivalent (boe/d)	**5,719**	7,311	(22)

Combined average production volumes decreased by 22 percent to 5,719 boe in 2003 from 7,311 boe per day in 2002 due to several factors. These mainly included dispositions of non-core properties of approximately 650 boe per day in late 2002, third-party processing facility problems throughout 2003 and normal production declines. Average oil production decreased 27 percent from 4,032 barrels per day in 2002 to 2,951 barrels per day in 2003 while average natural gas production decreased 16 percent from 19.7 mmcf per day in 2002 to 16.6 mmcf per day in 2003.

In the fourth quarter of 2003, combined average production decreased by 23 percent to 5,226 boe per day from 6,771 boe per day in the fourth quarter of 2002. The decline was related to disposition of non-core properties in late 2002, third-party processing facility problems and normal production declines. Average oil production in the fourth quarter of 2003 decreased 22 percent to 2,714 barrels per day from 3,477 barrels per day in the fourth quarter of 2002 while natural gas production decreased 24 percent to 15.1 mmcf per day in the fourth quarter of 2003 from 19.8 mmcf per day in the same quarter of 2002.

SELECTED FINANCIAL INFORMATION

	2003		2002	
Years ended December 31	**$000s**	**$/boe**	$000s	$/boe
Production revenue	**82,818**	**39.67**	81,557	30.56
Hedging loss	**(3,227)**	**(1.54)**	(6,184)	(2.32)
Production revenue after hedging	**79,591**	**38.13**	75,373	28.24
Royalties, net of ARTC	**(18,767)**	**(9.00)**	(17,399)	(6.51)
Production expenses	**(21,641)**	**(10.37)**	(22,628)	(8.48)
Net operating income	**39,183**	**18.76**	35,346	13.25
General & administrative expense	**(4,281)**	**(2.05)**	(4,547)	(1.70)
Interest expense	**(1,697)**	**(0.81)**	(1,990)	(0.75)
Current income taxes	**148**	**0.07**	(503)	(0.19)
Cash flow from operations before reorganization costs	**33,353**	**15.97**	28,306	10.61
Reorganization costs	**(4,905)**	**(2.35)**	–	–
Cash flow from operations	**28,448**	**13.62**	28,306	10.61
Stock-based compensation expense	**(143)**	**(0.07)**	–	–
Depletion, depreciation and amortization	**(31,156)**	**(14.93)**	(28,575)	(10.71)
Future income taxes	**3,211**	**1.54**	–	–
Net income (loss)	**360**	**0.16**	(269)	(0.10)

SELECTED THREE YEAR INFORMATION

($000s except per unit information)	**2003**	2002	2001
Gross production revenue	**82,818**	81,557	142,430
Income (loss) from operations	**1,906**	234	(75,345)
Net income (loss)	**360**	(269)	(80,673)
Net income (loss) per unit – basic	**0.03**	(0.02)	(7.90)
Net income (loss) per unit – diluted	**0.03**	(0.02)	(7.75)
Total assets	**156,594**	161,138	157,921
Bank debt	**36,059**	26,573	32,476

In 2003 and 2002, gross production revenue was significantly lower than that of 2001 as a major producing property – Boyer – was disposed of mid-year in 2001. This property sold for net proceeds of $107 million, and in accordance with the full cost method of accounting where crediting the proceeds to costs would result in a change of 20 percent or more to the Company's depletion rate, a loss on this sale of $53.3 million was recorded in 2001. Also, in 2001 contributing to the loss from operations and the loss, the Company terminated a proposed merger resulting in $4.3 million in related costs being expensed in the period and recorded a full cost accounting ceiling-test writedown of $99.8 million (net of future tax – $63.6 million).

Production Revenue

Gross production revenue increased by two percent from $81.6 million in 2002 to $82.8 million in 2003. This increase was due to a 22 percent decrease in production offset by a 30 percent increase in the average per boe sales price. Oil revenues accounted for 53 percent of gross production revenue, while natural gas provided the remaining 47 percent. Production revenue after hedging increased six percent in 2003 to $79.6 million from $75.4 million in 2002. The hedging loss was $6.2 million in 2002 compared to $3.2 million in 2003.

For the fourth quarter of 2003, gross production revenue decreased by 24 percent to $17.1 million from $22.4 million in the fourth quarter of 2002. This decrease is due to a 23 percent decrease in production. Production revenue after hedging decreased by 16 percent to $16.6 million in the fourth quarter of 2003 from $19.8 million in the fourth quarter of 2002. The hedging loss was $0.5 million in the fourth quarter of 2003 compared to a hedging loss of $2.6 million in the fourth quarter of 2002.

Benchmark West Texas Intermediate (WTI) crude oil averaged US$31.04 per barrel for 2003, an increase of US$4.96 per barrel compared to the US$26.08 average in 2002. Natural gas prices also increased significantly from 2002 to 2003. The Trust's average natural gas price for 2003 was $6.46 per mcf, an increase of 67 percent from the $3.86 per mcf in 2002. On a boe basis, prices received were $39.67 in 2003 compared to $30.56 in 2002, a 30 percent increase. After accounting for losses from hedging activities, the Trust's average price was $38.13 per boe in 2003, a 35 percent increase from $28.24 per boe in 2002.

Royalties

Royalties, which include Crown, freehold, First Nations and overriding royalties net of Alberta Royalty Tax Credit (ARTC) increased to 22.7 percent of gross production revenue for 2003, compared to 21.3 percent in 2002. This increase was a result of the increase in natural gas prices combined with lower natural gas cost allowance in 2003 compared to 2002.

Royalties in the fourth quarter of 2003 were $3.8 million or 22.5 percent of gross production revenue as compared to $5.0 million or 22.4 percent in the fourth quarter of 2002.

Years ended December 31	**2003**		2002	
	$000s	**% of Production Revenue**	$000s	% of Production Revenue
Crown royalties & mineral taxes	**10,271**	**12.4**	7,485	9.2
ARTC	**(387)**	**(0.4)**	(82)	(0.1)
Net Crown royalties	**9,884**	**12.0**	7,403	9.1
Freehold & overriding royalties	**2,773**	**3.3**	2,839	3.4
First Nations royalties	**6,110**	**7.4**	7,157	8.8
Total royalties	**18,767**	**22.7**	17,399	21.3

Production Expenses

Production expenses in 2003 averaged $10.37 per boe, an increase of 22 percent from $8.48 per boe in 2002. This increase in boe cost for the year was directly attributable to fixed costs associated with lower production volumes.

Production expenses in the fourth quarter of 2003 averaged $13.61 per boe, an increase of 54 percent from $8.81 per boe in the fourth quarter of 2002. This increase in boe costs for the quarter is a result of fixed costs associated with lower production volumes as well as field maintenance expenses of approximately $0.6 million which are not expected to recur.

General and Administrative Costs

General and administrative costs were $4.4 million in 2003 compared to $4.5 million in 2002, a decrease of three percent. On a unit-of-production basis, general and administrative costs increased to $2.12 per boe in 2003 from $1.70 per boe in 2002. Included in general and administrative costs in 2003 is stock-based compensation of $143,000 related to expensing of stock options that were issued during the year.

General and administrative costs for the fourth quarter of 2003 were $1.3 million, a decrease of 13 percent from $1.5 million in the corresponding quarter of 2002.

Capitalized general and administrative costs relating to acquisitions, development and exploration activities increased to $1.08 per boe in 2003 from $0.86 per boe in 2002 due to lower volumes in 2003.

Years ended December 31	**2003**		2002	
	$000s	**$/boe**	$000s	$/boe
G&A expensed (including stock-based compensation)	**4,424**	**2.12**	4,547	1.70
G&A capitalized	**2,251**	**1.08**	2,302	0.86
Total G&A costs	**6,675**	**3.20**	6,849	2.56

Interest Expense

Interest expense decreased 15 percent in 2003 to $1.7 million from $2.0 million in 2002. Higher interest rates in 2003 were offset by the decreased debt balance in the year mainly as a result of the dispositions at year-end 2002.

Interest expense in the fourth quarter of 2003 was $0.5 million, comparable to $0.6 million in the corresponding quarter of 2002. This decrease is a result of a higher average debt balance in the fourth quarter of 2002 prior to the disposition of properties at December 2002 compared to the fourth quarter of 2003.

Reorganization Costs

Reorganization costs associated with the Plan of Arrangement were $4.9 million. These costs consisted mainly of investment banker fees, legal fees and professional accounting and tax services.

Depletion, Depreciation and Amortization Expense

The depletion, depreciation and amortization expense (DD&A) in 2003, which includes the provision for future removal and site restoration, was $31.2 million or $14.93 per boe, an increase of nine percent from $28.6 million or $10.71 per boe in 2002. This increase in DD&A was a result of lower reserves and higher capital cost additions offset by lower production.

DD&A in the fourth quarter of 2003 was $9.0 million or $18.80 per boe, an increase of 21 percent from $7.5 million or $12.04 per boe in the fourth quarter of 2002. The quarter specifically reflects the revisions to the proved reserves under the new standards of disclosure for oil and natural gas activities, National Instrument 51-101 (NI 51-101) as mandated by the Canadian Securities Administrators for year-ends beginning with December 31, 2003.

Income Taxes

The Trust had a capital tax recovery of $148,000 in 2003 compared to an expense of $503,000 in 2002. The recovery is mainly a result of prior year adjustments. Current taxes consist of Large Corporations Tax and Saskatchewan Capital Tax.

Capital taxes in the fourth quarter of 2003 were a recovery of $62,000 compared to an expense of $61,000 in the fourth quarter of 2002. The recovery is a result of prior year adjustments.

The Trust has recorded a future income tax recovery in 2003 of $3.2 million as a result of a reduction in the valuation allowance at December 31, 2002. The amount of the reduction includes the tax impact of expenditures incurred for flow-through shares during the period, income earned in the period, reduction in future federal tax rates and adjustment of tax basis. At December 31, 2003 the Trust had a total of approximately $143.0 million of tax pools available for future applications.

TAX POOLS

Years ended December 31 ($000s)	**2003**	2002
Undepreciated capital costs	**57,058**	65,291
Canadian exploration expenses	**11,988**	31,170
Canadian development expenses	**39,008**	60,055
Canadian oil and gas property expenses	**19,046**	2,228
Non-capital losses	**14,225**	8,242
Other	**1,319**	2,476
Total tax pools	**142,644**	169,462

Cash Flow and Net Income

Cash flow from operations was $28.4 million or $2.43 per unit in 2003, comparable to $28.3 million or $2.59 per share in 2002. Cash flow for 2003 is net of reorganization costs of $4.9 million.

For the fourth quarter of 2003, the Trust recorded a negative cash flow from operations of $0.2 million or $0.02 per unit compared to cash flow from operations of $7.2 million or $0.65 per share in the fourth quarter of 2002. This decrease is a result of the reorganization costs of $4.9 million associated with the Plan of Arrangement incurred in the quarter, lower production revenue and higher operating costs in the fourth quarter compared to the fourth quarter of 2002.

The Trust recorded net income of $0.4 million in 2003 compared to a loss of $0.3 million in 2002. The 2003 increase was a result of higher production revenue offset by higher DD&A and reorganization costs. On a per unit/share basis, net income was $0.03 in 2003 compared to a loss of $0.02 in 2002.

For the fourth quarter of 2003 the Trust recorded a loss of $9.2 million or $0.79 per unit compared to a loss of $0.3 million or $0.03 per share in the same period of 2002. The loss in 2003 is a result of reorganization costs combined with increased DD&A, lower production revenue and higher operating expenses.

CAPITAL EXPENDITURES

Years ended December 31 ($000s)	**2003**	2002
Land and lease	**4,088**	1,891
Geological and geophysical	**3,977**	3,642
Drilling and completions	**20,676**	15,556
Equipment and facilities	**10,789**	14,406
Overhead and office equipment	**2,602**	2,390
Total exploration and development	**42,132**	37,885
Property acquisitions (dispositions) net	**3**	(9,095)
Total capital expenditures	**42,135**	28,790

Exploration and development expenditures increased by 11 percent from $37.9 million in 2002 to $42.1 million in 2003.

Liquidity and Capital Resources

The Trust's capital investments in 2003 were funded by cash flow and the use of bank debt.

At year-end, the Trust had a credit facility with a Canadian chartered bank for $45.0 million, consisting of a $43.0 million revolving operating demand loan and a $2.0 million non-revolving demand loan. The demand loan was only available until January 30, 2004 at which time it was repaid. The credit facility bears interest at the bank's prime lending rate.

Net debt at December 31, 2003, including a working capital deficiency of $8.8 million, was $44.9 million compared to $44.7 million at September 30, 2003 and $35.6 million at December 31, 2002. Proceeds from dispositions in December 2002 resulted in a reduced bank line at December 2002 compared to December 2003.

Pursuant to various agreements with the Trust's lender, the Trust is restricted from making distributions to its unitholders under such agreements in the following circumstances: (i) after demand has been made under the credit facilities; (ii) after the Trustee has received notice of a default or event of default under the credit facilities or of the borrowings thereunder exceeding the borrowing base established from time-to-time by the lender; and (iii) out of the ordinary course of business.

A substantial amount of the Trust's capital spending is discretionary in nature. The Trust generally has a high working interest and operatorship of its major properties. Therefore, the Trust can control the timing of expenditures to match financial resources. The Trust also engages in commodity price hedging in order to reduce the volatility of cash flow available for its capital program.

Change in Accounting Policy

The Trust has elected to prospectively adopt amendments to CICA Handbook Section 3870, "Stock-Based Compensation and Other Stock-Based Payments" pursuant to the transitional provisions contained therein. Under this amended standard, the Trust must account for compensation expense based on the fair value of rights granted under its unit-based compensation plan. No rights were granted at December 31, 2003; however, the adoption of these amendments also impacted the stock options outstanding prior to the Plan of Arrangement. Compensation expense of $143,000 was recorded for all stock options granted on or after January 1, 2003. A corresponding amount was recorded as contributed surplus, which was reclassified in 2003 to unitholders' capital as all these options were exercised in the year.

Quarterly Information

($000s except per unit information)

2003	Revenue	Net income (loss)	Net income (loss)/unit basic	Net income (loss)/unit diluted	Cash flow (outflow) from operations	Cash flow/unit basic	Cash flow/unit diluted
1st quarter	**23,469**	**6,162**	**0.53**	**0.53**	**11,578**	**0.99**	**0.99**
2nd quarter	**20,733**	**1,899**	**0.16**	**0.16**	**9,444**	**0.81**	**0.81**
3rd quarter	**18,750**	**1,512**	**0.13**	**0.13**	**7,651**	**0.65**	**0.65**
4th quarter	**16,639**	**(9,213)**	**(0.79)**	**(0.78)**	**(225)**	**(0.02)**	**(0.02)**
Total year	**79,591**	**360**	**0.03**	**0.03**	**28,448**	**2.43**	**2.43**

For fourth quarter information analysis, see relevant sections in the Management's Discussion and Analysis.

Production revenue after hedging has declined quarter-over-quarter in 2003 due to both pricing and production declines. In the first quarter of 2003, crude oil prices were 22 percent higher than in the 2nd quarter of 2003. This reduction was offset slightly by a reduction in the hedging loss in the 2nd quarter as prices declined. From the second to the third quarter, crude oil prices were comparable while the natural gas price decreased by 13 percent resulting in lower revenue in the third quarter. Production from the first to the third quarter ranged between 5,800 to 6,000 boe per day; however, production in the fourth quarter declined by 10 percent from the third quarter.

Net income in the second quarter was significantly less than in the first quarter. Production revenue after hedging was $2.7 million higher in the first quarter, which, combined with a future tax recovery on flow-through expenditures incurred in the first quarter of $1.9 million resulted in the higher net income first quarter over the second quarter. A loss was incurred in the fourth quarter compared to the other quarters. This was due to reorganization costs of $4.9 million, additional DD&A as discussed under this section in this MD&A, higher operating costs and lower production revenue in the fourth quarter.

($000s except per share information)

2002	Revenue	Net income (loss)	Net income (loss)/share basic	Net income (loss)/share diluted	Cash flow (outflow) from operations	Cash flow/share basic	Cash flow/share diluted
1st quarter	17,977	1,092	0.10	0.10	7,930	0.73	0.73
2nd quarter	19,064	(234)	(0.02)	(0.02)	6,667	0.61	0.61
3rd quarter	18,510	(787)	(0.07)	(0.07)	6,550	0.60	0.60
4th quarter	19,822	(340)	(0.03)	(0.03)	7,159	0.65	0.65
Total year	75,373	(269)	(0.02)	(0.02)	28,306	2.59	2.59

For per unit comparison purposes, the number of shares for 2002 has been converted on a three-for-one basis.

Related Party Transactions

During 2003, a $250,000 advance to a former officer of the Company was repaid. Also during the year, the Trust incurred $573,000 in legal fees, which included costs associated with the reorganization to a Trust, to a firm in which a director of the Company is a partner.

Pursuant to agreements dated December 31, 2003, three senior executives are entitled to receive a total of $1.5 million in retention bonuses payable in trust units based on the market price at the time of issue, payable in equal semi-annual payments over the next two years subject to certain conditions.

Contractual Obligations and Contingencies

No material contractual obligations exist at December 31, 2003 other than those future regulatory obligations to abandon and restore wells and facility locations. At December 31, 2003 the Trust has estimated the future removal and site restoration costs to be approximately $15.0 million.

Impact of New Accounting Pronouncements

In December 2002, the Canadian Institute of Chartered Accountants issued a new standard on the accounting for asset retirement obligations. This standard requires recognition of a liability for the future retirement obligations associated with property, plant and equipment. These obligations are initially measured at fair value, which is the discounted future value of the liability. This fair value is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the date of expected settlement of the retirement obligations. The new standard is effective for all fiscal years beginning on or after January 1, 2004. The estimated impact, subject to revision, of this new standard at January 1, 2004 will be an increase to property, plant and equipment of approximately $2.9 million, an increase to asset retirement obligation of approximately $0.7 million and an increase to retained earnings of approximately $2.2 million.

Accounting Guideline 16 (AcG-16) issued by the CICA, a revised guideline for full cost oil and gas accounting, will be adopted by the Trust effective January 1, 2004. Under AcG-16, the fair values of the oil and natural gas assets are considered in determining the recoverability of the net book value. The estimated future cash flow of proved plus probable reserves is discounted at the risk-free rate of return to determine the fair value of the oil and natural gas assets. These cash flows are determined based on management's best estimate of future prices and operating environment assumptions. Had this policy been adopted in 2003, the Trust would have recorded an impairment of approximately $15.0 million at December 31, 2003. The adoption of this policy on January 1, 2004 will result in a charge to retained earnings of approximately $15.0 million.

Critical Accounting Estimates

Certain estimates are used or made by management when preparing the financial statements. Three of the more significant ones are the depletion, depreciation and amortization (DD&A) expense, impairment of oil and natural gas properties and the future removal and site restoration costs. These estimates use reserves estimates as prepared by independent reservoir engineers and future costs estimates. By their nature, these estimates and those related to the assessment of future cash flows used to assess impairment, are subject to measurement uncertainty and could have an impact on the financial statements of future periods.

Recent Events and Outlook

In the first quarter of 2004, the Trust completed the acquisition of certain properties in southeastern Saskatchewan (the Wapella property) and the acquisition of a private company – Java Energy Inc. (Java). These acquisitions increased the Trust's reserve base by 64 percent and the production base by 40 percent. This, in combination with the 138,000 net acres of development acreage and in excess of $50 million in development inventory projects, is expected to add stability and potential growth to the Trust.

In January, 2004, the Trust raised $57.5 million on the issuance of 5.75 million Trust units, and used $36.0 million of these proceeds to purchase the Wapella property. The remainder of the proceeds was used to pay down bank debt and for development of existing inventory. In late February, 2004, the Trust completed the Java acquisition for total consideration of $21.8 million which included approximately $8.0 million in assumed debt and working capital deficiency and the issuance of 1.5 million Series B exchangeable shares.

For 2004, 20-25 percent of the cash flow from operations is expected to be retained in the Trust and utilized for its capital program. These funds will be used for drilling of development wells, waterflood and tie-in projects, over half of which is expected to be incurred in the first quarter of 2004 when winter access is optimal. The remaining cash flow from operations in 2004 will be distributed to the Trust unitholders. The Trust paid distributions in January and February of 2004 and declared distributions in March 2004 (payable April 15, 2004) of 15 cents per unit.

As at March 23, 2004, the Trust has a banking facility of $50 million subject to periodic review. Approximately $34.0 million was drawn at March 23, 2004.

Business Risks

The business of exploring, developing, acquiring and producing oil and natural gas is subject to a variety of operational, financial and regulatory risks.

Operational risks include finding and developing oil and natural gas reserves on an economic basis, reservoir production performance, marketing, production, hiring and retention of employees and accessing contract services on a cost-effective basis. The Trust mitigates these risks by employing a team of highly qualified professionals with a compensation system that rewards performance and by developing long-term relationships with contract service providers. The Trust maintains an insurance program consistent with industry practice to protect against destruction of assets, well blowouts, pollution and other business interruptions. The Trust generally follows a strategy of acquiring and exploiting producing assets and maximizing these assets through relatively lower-risk development. The Trust makes appropriate use of advanced technology, such as three-dimensional seismic, to reduce the risk of its drilling programs.

Financial risks include commodity prices, interest rates and the Canada/U.S. dollar exchange rate, all of which are beyond the control of the Trust. The Trust's earnings and cash flow from operations are highly sensitive to changes in factors that are beyond its control. The Trust's approach to management of these risks is to maintain a prudent level of debt and a strong financial position to fund exploration and development activities and acquisitions through fluctuations in these variables. The Trust uses financial instruments to manage exposures related to petroleum and natural gas prices, interest rates and exchange rates. Such financial instruments are not used by the Trust for trading or speculative purposes.

For calendar 2004, the Company has entered into oil price swaps for an average volume of approximately 1,800 barrels per day at an average WTI price of US$27.69. The Trust is exposed to losses in the event of default by the counterparties to these derivative instruments. All of the Trust's derivative contracts are with a Canadian chartered bank. In periods when WTI prices are higher than the hedged price, the Trust is also exposed to cash collateral payments on mark to market. At this time, the Trust is required to place cash collateral for mark to market over US$2.5 million. With the acquisition of the Wapella property, the Trust has a physical hedge commitment of 300 barrels per day at US$27.68 WTI for calendar 2004.

Government regulation has an impact on all aspects of the business of the Trust, including environmental regulation. Changes in government regulation with respect to taxation, royalties and environmental and safety regulation are beyond the control of the Trust. The Trust mitigates risks with respect to environmental and safety matters by taking a proactive approach including conducting environmental reviews with respect to all material acquisitions, construction of modern facilities which meet or exceed current environmental standards and enforcing high safety standards with respect to its employees and contractors. The Trust also has an operational emergency response plan in place and is in substantial compliance with current environmental legislation. As well, the Trust has significant financial exposure related to the future costs of abandoning and restoring producing properties and facilities at the end of their economic life.

Outstanding Unit Information

At March 23, 2004, the Trust had 18.8 million units, 0.3 million Series A exchangeable shares and 0.4 million Series B exchangeable shares outstanding. The exchange ratio at March 15, 2004 for the series A exchangeable shares was 1.02992 Trust units per exchangeable share and the exchange ratio for the Series B exchangeable shares was 1.01498 Trust units per exchangeable share.

Other Information on the Trust

Other information concerning the Trust can be located at www.sedar.com under NAV Energy Trust.

MANAGEMENT'S REPORT

To the Unitholders of NAV Energy Trust:

The preparation and presentation of the accompanying consolidated financial statements is the responsibility of management. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles and necessarily include estimates which are based on management's best judgement. Information contained elsewhere in the annual report is consistent, where applicable, with that contained in the financial statements.

Management is responsible for installing and maintaining a system of internal controls to provide reasonable assurance that assets are safeguarded and that reliable financial information is produced for preparation of the financial statements.

Independent auditors are appointed by the Trust's unitholders to perform an examination of the corporate and accounting records so as to express an opinion on the financial statements. Their examination included a review and evaluation of the Trust's system of internal controls and included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are fairly presented.

The Board of Directors is responsible for ensuring management's performance of its responsibilities for financial reporting and internal control. The Board exercises this responsibility with the assistance of the Audit Committee. The Audit Committee meets with management and the independent auditors to satisfy itself that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the financial statements be presented to the Board of Directors for approval.

Thomas P. Stan
President & Chief Executive Officer

Janalee F. Shutiak
Vice President & Chief Financial Officer

Calgary, Alberta
March 12, 2004

AUDITORS' REPORT

To the Unitholders of NAV Energy Trust:

We have audited the consolidated balance sheets of NAV Energy Trust as at December 31, 2003 and 2002 and the consolidated statements of operations and accumulated loss and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Calgary, Alberta
March 12, 2004

CONSOLIDATED BALANCE SHEETS

As at December 31 ($000s)	2003	2002
	(Notes 1 and 3)	
ASSETS		
Current		
Restricted cash (Note 11)	**2,567**	–
Accounts receivable (Note 12)	**9,012**	10,171
	11,579	10,171
Property and equipment (Notes 3 and 4)	**145,015**	150,967
	156,594	161,138
LIABILITIES		
Current		
Accounts payable and accrued liabilities	**20,384**	19,204
Bank debt (Note 5)	**36,059**	26,573
	56,443	45,777
Future removal and site restoration (Note 4)	**8,119**	7,525
	64,562	53,302
UNITHOLDERS' EQUITY		
Unitholders' capital (Note 6)	**130,237**	158,267
Exchangeable shares (Note 6)	**11,636**	–
Contributed surplus (Note 6)	**230**	–
Accumulated loss	**(50,071)**	(50,431)
	92,032	107,836
	156,594	161,138

See Notes to the Consolidated Financial Statements

Approved by the Board:

Director

Director

CONSOLIDATED STATEMENTS OF OPERATIONS AND ACCUMULATED LOSS

For the years ended December 31 ($000s, except unit and per unit amounts)	2003	2002
	(Notes 1 and 3)	
REVENUE		
Petroleum and natural gas sales	**79,591**	75,373
Royalties, net of Alberta Royalty Tax Credit	**(18,767)**	(17,399)
	60,824	57,974
EXPENSES		
Production	**21,641**	22,628
General and administrative (Note 4)	**4,424**	4,547
Interest on bank debt	**1,697**	1,990
Depletion, depreciation and amortization (Note 4)	**31,156**	28,575
	58,918	57,740
INCOME FROM OPERATIONS	**1,906**	234
Reorganization expenses (Note 3)	**4,905**	–
INCOME (LOSS) BEFORE TAXES	**(2,999)**	234
TAXES (Note 8)		
Capital taxes	**(148)**	503
Future income taxes	**(3,211)**	–
	(3,359)	503
NET INCOME (LOSS)	**360**	(269)
ACCUMULATED LOSS, BEGINNING OF YEAR	**(50,431)**	(50,162)
ACCUMULATED LOSS, END OF YEAR	**(50,071)**	(50,431)
Net income (loss) per unit		
Basic	**0.03**	(0.02)
Diluted (Note 6)	**0.03**	(0.02)
Weighted average number of units outstanding (Note 6)		
Basic	**11,694,494**	10,904,996
Diluted	**11,713,618**	10,940,660

See Notes to the Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 ($000s)	2003	2002
	(Notes 1 and 3)	
CASH FLOWS RELATED TO THE FOLLOWING ACTIVITIES		
OPERATING		
Net income (loss)	**360**	(269)
Add (deduct):		
Depletion, depreciation and amortization	**31,156**	28,575
Future income taxes	**(3,211)**	–
Stock-based compensation	**143**	–
Cash flow from operations	**28,448**	28,306
Changes in non-cash operating working capital items	**2,339**	(1,911)
	30,787	26,395
FINANCING		
Increase (decrease) in bank debt	**9,486**	(5,903)
Common shares issued for cash, net of expenses (Note 6)	**–**	8,504
Proceeds on exercise of stock options (Note 6)	**5,424**	549
Common shares repurchased	**(443)**	–
	14,467	3,150
INVESTING		
Property and equipment expenditures	**(42,132)**	(37,885)
Property acquisitions	**(201)**	–
Property dispositions	**198**	9,095
Removal and site restoration costs incurred	**(552)**	(755)
	(42,687)	(29,545)
NET INCREASE IN CASH	**2,567**	–
CASH, BEGINNING OF YEAR	**–**	–
CASH, END OF YEAR	**2,567**	–

See Notes to the Consolidated Financial Statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2003 and 2002

(all tabular amounts are in $000s, except unit and per unit amounts)

1. Structure of the Trust

Pursuant to a Plan of Arrangement (the "Plan") the shareholders of Navigo Energy Inc. (the "Company") approved a reorganization into NAV Energy Trust (the "Trust") pursuant to which the Company became a wholly-owned subsidiary of the Trust. The Plan received the approval of the Court of Queen's Bench and the Trust began operations effective December 29, 2003.

The Trust is an open-end unincorporated investment trust created under the laws of Alberta pursuant to a Trust Indenture dated November 12, 2003, amended from time-to-time. The beneficiaries of the Trust are the holders of trust units ("unitholders"). The Trust was established to hold, directly and indirectly, interests in petroleum and natural gas properties. Cash flow is provided to the Trust from the properties owned and operated by the Company. Cash flow is paid from the Company to the Trust by way of royalty payments, interest payments and principal repayments. The cash payments received by the Trust are subsequently distributed to the unitholders monthly.

Prior to the implementation of the Plan of Arrangement on December 29, 2003, the consolidated financial statements included the accounts of the Company, its wholly-owned subsidiary, Edge Energy Inc. and their wholly-owned oil and gas partnership, Navigo Energy Partnership. After giving effect to the Plan of Arrangement, the consolidated financial statements have been prepared on a continuity-of-interests basis which recognizes the Trust as the successor entity to the Company. The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP") and except as outlined below, are consistent with the accounting policies set out in the 2002 Annual Report of Navigo Energy Inc.

2. Significant Accounting Polices

Basis of presentation

The consolidated financial statements include the accounts of the Trust and its wholly-owned subsidiaries. The comparative figures are those of the Company and its subsidiaries.

Full cost accounting

The Trust follows the full cost method of accounting whereby all costs relating to the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre and charged against income, as set out below. Such costs include land acquisition, drilling, geological and geophysical, production facilities and overhead expenses related to exploration and development activities. These costs are depleted and depreciated on a unit-of-production method using estimated gross proved petroleum and natural gas reserves as determined by independent engineers. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of six thousand cubic feet of natural gas equating to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether proved reserves are attributable to the properties or impairment occurs. Costs of production facilities are depreciated on a unit-of-production basis.

Gains or losses on sales of properties are recognized only when crediting the proceeds to costs would result in a change of 20 percent or more in the depletion rate.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). Under this test, an estimate is made of the ultimate recoverable amount from future net revenues using proved reserves and year-end prices, plus the net costs of major development projects and unproved properties, less future removal and site restoration costs, overhead, financing costs and income taxes. If net carrying costs exceed the ultimate recoverable amount, additional depletion and depreciation is provided (see Note 4).

Provision for future removal and site restoration costs

Estimates are made of the future removal and site restoration costs relating to the Trust's petroleum and natural gas properties at the end of their economic life, based on year-end costs, in accordance with current legislative requirements and industry practice. Annual charges are provided for on a unit-of-production basis. Actual expenditures incurred are applied against the provision for future removal and site restoration costs.

Foreign currency

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at year-end exchange rates. Non-monetary items are translated at the average exchange rate during the month they are recognized. Exchange gains or losses are included in income in the year incurred.

Measurement uncertainty

The amounts recorded for depletion, depreciation and amortization and future removal and site restoration costs are based on estimates of reserves and future costs. By their nature, these estimates and those related to the assessment of future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material.

Joint interests

A portion of the Trust's exploration, development and production activities are conducted jointly with others. These financial statements reflect only the Trust's proportionate interest in such activities.

Revenue recognition

Revenue associated with sales of crude oil, natural gas, and natural gas liquids is recognized when title passes to the purchaser, normally at the pipeline delivery point for natural gas and at the wellhead for crude oil.

Flow-through shares

In 2002 and prior years, the Company financed a portion of its exploration and development activities through the issue of flow-through shares. Under the terms of the flow-through share agreements, the tax attributes of the related expenditures were renounced to the subscribers. Share capital and the valuation allowance related to the future tax asset and the future income tax liability were reduced by the estimated cost of the renounced tax deductions at the time the expenditures were made.

Hedging

The Trust periodically utilizes certain financial instruments to reduce exposures related to petroleum and natural gas prices and foreign exchange fluctuations on a portion of its crude oil and natural gas production. Gains and losses on these contracts, all of which must constitute effective hedges, are recognized in revenue concurrently with the hedged transaction. If hedge requirements are not met, the financial instruments are recorded at fair value; any gains or losses are included in income in the period.

Future income taxes

The Trust follows the liability method of accounting for income taxes. Under this method future tax assets and liabilities are determined based on differences between the financial reporting and tax basis of assets and liabilities and measured using the substantively enacted tax rates and laws that are currently in effect when the differences are expected to reverse.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. As the Trust allocates all of its taxable income to the unitholders in accordance with the Trust Indenture, and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income tax expense has been made in the Trust.

In the Trust structure, payments are made between the Company and the Trust which result in the transferring of taxable income from the Company to individual unitholders. These payments may reduce future income tax liabilities previously recorded by the Company which would be recognized as a recovery of income tax in the period the expenditures are incurred.

Unit-based compensation

The Trust has unit-based compensation plans, which are described in Note 6. Compensation expense is measured based on the intrinsic value of the award at the date of the grant and is recognized over the vesting period. Any consideration received by the Trust upon exercise of the unit rights is credited to unitholders' capital.

Prior to the Plan of Arrangement, the Company had stock-based compensation plans. The Trust has elected to prospectively adopt amendments to CICA Handbook Section 3870 "Stock-based Compensation and Other Stock-based Payments" pursuant to the transitional provisions contained therein. Adoption of these amendments impacted the stock options outstanding prior to the Plan of Arrangement. Compensation expense for the 2003 year has been included in general and administrative expenses and disclosed for prior years in Note 6.

Per unit amounts

Net income per unit is calculated using the weighted average number of units (or common shares to December 31, 2002) outstanding during the year, including the weighted average number of exchangeable shares outstanding converted at the exchange ratio at the end of each month. Diluted net income per unit is calculated using the treasury stock method to determine the dilutive effect of unit-based compensation. The treasury method assumes that the proceeds received from the exercise of "in the money" unit rights are used to repurchase and cancel units at the average trading price for the period.

3. Transfer of Assets and Liabilities Pursuant to Plan of Arrangement

Under the Plan of Arrangement effective on December 29, 2003, certain assets were transferred to C1 Energy Ltd. being undeveloped land, seismic and producing oil and gas properties. As this was a related party transaction, assets and liabilities were transferred at book value. Details are as follows:

Undeveloped land and seismic	$ 9,911
Petroleum and natural gas properties and equipment	8,518
Total assets transferred	18,429
Provision for site restoration and abandonment	352
Net assets transferred and reduction in share capital	$ 18,077

Tax pools totalling approximately $27 million were transferred to C1 Energy Ltd. Associated with the Plan of Arrangement, the Company recorded reorganization costs of $4.9 million.

4. Property and Equipment

	Cost $	Accumulated Depletion, Depreciation and Amortization $	Book Value $
December 31, 2003			
Petroleum and natural gas properties	**383,401**	**238,386**	**145,015**
December 31, 2002			
Petroleum and natural gas properties	359,695	208,728	150,967

At December 31, 2003, $27.2 million (2002 – $34.3 million) of costs relating to unproved properties were excluded from costs subject to depletion.

During 2003, $2.3 million (2002 – $2.3 million) of general and administrative expenses relating to exploration and development activities were capitalized.

A provision of $1.5 million was recorded for future removal and site restoration for the year ended December 31, 2003 (2002 – $1.8 million) and was included in depletion, depreciation and amortization expense.

The ceiling test in 2003 was calculated using year-end prices of $38.94 per barrel of oil and $5.89 per mcf of natural gas, year-end costs and reserves and no write-down was required. In 2002, using prices of $41.90 per barrel of oil and $6.02 per mcf of natural gas, no write-down was required.

Accounting Guideline 16 ("AcG-16") issued by the Canadian Institute of Chartered Accountants, a revised guideline for full cost oil and gas accounting will be adopted by the Trust effective January 1, 2004. Under AcG-16, the fair values of the oil and natural gas assets are considered in determining the recoverability of the net book value. The estimated future cash flow of proved plus probable reserves is discounted at the risk-free rate of return to determine the fair value of the oil and natural gas assets. These cash flows are determined based on management's best estimate of future prices and operating environment assumptions. Had this policy been adopted in 2003, the Trust would have recorded an impairment of approximately $15.0 million at December 31, 2003. The impact of this impairment would have been a reduction in net income per unit of $1.28 basic and diluted. The adoption of this policy on January 1, 2004 will result in a charge to retained earnings of approximately $15.0 million.

5. Bank Debt

The Trust has a bank facility in the amount of $45 million consisting of a $43 million revolving operating demand loan (2002 – $55 million) and a $2 million non-revolving demand loan. The $2 million non-revolving demand loan was available only until January 30, 2004 and was repaid. The interest rate on outstanding debt varies but approximates the bank's prime lending rate. The facility is secured by a charge over all of the Trust's assets. Drawn under this facility at December 31, 2003 was $36.1 million (2002 – $26.6 million). The facility is guaranteed by the Trust and is secured by a $100 million demand debenture with a floating charge over all the Company and the Trust's current and after-acquired property and an undertaking to grant a fixed charge on major producing petroleum and natural gas reserves.

6. UNITHOLDERS' CAPITAL AND EXCHANGEABLE SHARES

a) Authorized

The Trust is authorized to issue an unlimited number of Trust units.

b) Issued and outstanding

Pursuant to the Plan of Arrangement, for every three shares of the Company, shareholders received either one unit of the Trust or one Exchangeable share and one share of a new public exploration and production company, C1 Energy Ltd. On December 29, 2003, the effective date of the Plan of Arrangement, 11,192,295 Trust units and 1,000,000 exchangeable shares were issued upon the cancellation of all outstanding common shares of the Company.

Exchangeable shares

The exchangeable shares of the Company are convertible at any time into Trust units (at the option of the holder) based on the exchange ratio. The exchange ratio is increased monthly based on the cash distribution paid on the Trust units divided by the five-day weighted average unit price preceding the record date. Cash distributions are not paid on the exchangeable shares. On the tenth anniversary of the issuance of the exchangeable shares, subject to extension of such date by the Board of Directors of the Company, the exchangeable shares will be redeemed for Trust units at a price equal to the value of that number of Trust units based on the exchange ratio as at the last business day prior to the redemption date.

Unit or share capital

	Number of units/shares	Amount $
Balance, December 31, 2001	32,491,338	149,214
Stock options exercised	220,000	549
Flow-through shares issued	2,337,720	8,504
Balance, December 31, 2002	35,049,058	158,267
Stock options exercised	1,678,900	5,424
Stock-based compensation	–	143
Repurchase of shares pursuant to normal course issuer bid	(151,077)	(673)
Tax effect of renounced expenditures	–	(3,211)
Balance, December 29, 2003 prior to Plan of Arrangement	36,576,881	159,950
Reduction in share capital pursuant to Plan of Arrangement (Note 3)	–	(18,077)
Balance, prior to conversion to Trust units and exchangeable shares	36,576,881	141,873
Conversion to Trust Units and Exchangeable Shares (3:1)		
Trust units issued in exchange for common shares	11,192,295	130,237
Exchangeable shares issued in exchange for common shares	1,000,000	11,636
Total Trust units and exchangeable shares outstanding, December 31, 2003	**12,192,295**	**141,873**

On the repurchase of shares pursuant to a normal course issuer bid, the cost of the shares were less than the stated value, resulting in contributed surplus of $230,000.

On December 19, 2002, the Company issued 2,337,720 flow-through common shares at $3.85 per share, for aggregate proceeds of $9,000,000 ($8,504,000 net of commission and other share issue costs of $496,000). The tax effect of this renouncement was recorded in 2003 at the time the related expenditures were made.

c) Trust Unit Rights Incentive Plan and other option plans

The Trust Unit Rights Incentive Plan (the "Rights Plan") was established as part of the Plan of Arrangement. The Trust may grant rights to employees, directors, consultants and other service providers of the Trust and any of its subsidiaries. The Trust is authorized to grant up to 1,219,230 rights. The initial exercise price of rights granted under the Rights Plan is equal to the closing trading price on the market the day the grant is given. Subsequently, the exercise price per right is calculated by deducting from the grant price the aggregate of all distributions, on a per unit basis, made by the Trust after the Grant Date, provided the aggregate amount of such monthly distributions represents a return of more than 0.416 percent of the Trust's recorded cost of oil and natural gas properties, less accumulated depreciation and depletion and any future income tax liability associated with such oil and natural gas properties at the end of each month. The rights have a life of five years and vest equally over a three-year period commencing on the first anniversary of the grant. No rights were granted as at December 31, 2003 under this plan.

The Company had a stock option plan whereby, prior to the Plan of Arrangement, options to purchase shares could be granted to employees, consultants and directors at an exercise price as determined by the board of directors. Immediately prior to the Plan of Arrangement, the 2,819,100 options issued and outstanding vested resulting in 1,556,400 options being exercised, 822,500 options being cancelled, and 440,200 carried over into the Trust. At December 31, 2003, there remained 146,733 options (after consolidation) outstanding at an average price of $9.38 per option.

Effective January 1, 2002, Canadian accounting standards require disclosure of the impact on net income of using the fair value method for stock options issued on or after January 1, 2002. If the fair value method had been used, net income for the year ended December 31, 2002 would have been reduced by $649,000. For the year ended December 31, 2003, the effect of the fair value method for stock options issued during this period of $143,000 has been recorded as a cost to general and administrative expenses.

d) Per Unit Amounts

The following table summarizes the Trust Units used in calculating Net income (loss) per unit.

	2003	2002
Weighted average number of units outstanding – Basic	**11,694,494**	10,904,996
Effect of stock options	**19,124**	35,664
Weighted average number of units outstanding – Dilutive	**11,713,618**	10,940,660

For loss per unit comparison purposes, the shares outstanding at December 31, 2002 have been converted on a three-for-one basis.

7. Cash Distributions Payable

The Trust has income for each year which includes all interest income from the Company, and other income, which accrues to the Trust to the end of the year. Under the Trust Indenture, taxable income of the Trust for each year will be paid or payable by way of cash distributions to the unitholders. No distributions were declared for the year ended December 31, 2003.

8. Income Taxes

The components of the future income tax liability at December 31, 2003 and 2002 are as follows:

	2003 **$**	2002 $
Future income tax assets (liabilities)		
Property and equipment	**(1,456)**	2,823
Future income tax benefits		
Site restoration	**2,809**	3,160
Share issue costs	**317**	903
	1,670	6,886
Future tax benefits not recognized due to uncertainty of utilization	**(1,670)**	(6,886)
Net future income tax liability	**–**	–

The provision for income taxes differs from the result that would be obtained by applying the combined Canadian Federal and Provincial statutory income tax rates to income (loss) before taxes. This difference results from the following:

	2003 **$**	2002 $
Valuation allowance – beginning of year	**6,886**	6,532
Income (loss) before taxes	**(2,999)**	234
Expected income taxes at the statutory rate of 40.7% (2002 – 42%)	**(1,221)**	98
Increase (decrease) in taxes resulting from:		
Crown royalties, (net of ARTC)	**3,619**	3,135
Resource allowance	**(2,118)**	(2,520)
Other	**337**	(1,067)
Utilized (not recognized) for tax on income earned (loss incurred) in period	**617**	(354)
Adjustment of tax basis and reduction of future income tax rates	**1,388**	–
Reduction in valuation allowance on tax impact of expenditures incurred on flow-through	**3,211**	–
Valuation allowance – end of year	**1,670**	6,886

The Trust has included a valuation allowance of $1.7 million at December 31, 2003 (2002 – $6.9 million) due to the uncertainty associated with being able to utilize these tax benefits in the future.

The Trust's petroleum and natural gas properties and facilities have an approximate tax basis of $142.6 million (2002 – $169.5 million) available for future use as deductions from taxable income. Included in this tax basis are estimated non-capital loss carry-forwards of $14.2 million (2002 – $8.2 million) which expire in various years through to 2008.

9. Financial Instruments

The carrying value of the Trust's cash, accounts receivable and accounts payable approximates fair value due to the short-term nature of these items. The Trust's bank debt bears interest at a floating market rate. Accordingly, no significant difference exists between the fair value and the carrying value.

Substantially all of the Trust's accounts receivable are due from customers in the oil and gas industry and are subject to the normal industry credit risks. The carrying value of accounts receivable reflects management's assessment of the associated credit risks.

10. Supplementary Cash Flow Information

The following net cash payments have been included in the determination of income:

	2003 **$**	2002 $
Interest paid	**1,488**	1,757
Taxes paid	**507**	720

11. Hedging Contracts

The nature of the Trust's operations results in exposure to fluctuations in commodity prices, foreign exchange rates and interest rates. The Trust monitors and, when appropriate, utilizes derivative financial instruments to hedge its exposure to these risks. The fair values of these derivative instruments are based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity.

The Trust is exposed to losses in the event of default by the counterparties to these derivative instruments. All of the Trust's derivative contracts are with a Canadian chartered bank.

In 2003, petroleum and natural gas sales were reduced by $3.2 million (2002 – $6.2 million) due to crude oil and natural gas hedging activities.

At December 31, 2003, the Trust has the following contracts outstanding for the periods indicated:

	Period	Volume	Hedged Price	Index
Oil price swap	January 1, 2004 – March 31, 2004	300 bbls/d	US $29.10	WTI
Oil price swap	January 1, 2004 – June 30, 2004	500 bbls/d	US $28.14	WTI
Oil price swap	Calendar 2004	500 bbls/d	US $27.33	WTI
Oil price swap	Calendar 2004	500 bbls/d	US $27.50	WTI
Oil price swap	Calendar 2004	500 bbls/d	US $27.80	WTI

Associated with these hedges is a US$0.05 per barrel administration fee. At December 31, 2003, settlement of these contracts would have resulted in a loss of US$1.9 million. Of this amount, the Company paid a cash collateral payment of US$1.5 million or CDN$2.0 million that has been classified as part of the restricted cash on the balance sheet. The remainder of the restricted cash balance of $0.6 million is collateral retained by the Company's previous bankers to cover December 2003 hedging commitments not paid until January 2004. The Company plans to hold all the contracts that are outstanding at December 31, 2003 to maturity.

12. Related Party Transactions

During 2003, a $250,000 advance to a former officer of the Company was repaid. During the year, the Trust incurred $573,000 (2002 – $283,000) in legal fees including costs associated with the reorganization to a firm in which a director of the Company is a partner.

Pursuant to agreements dated December 31, 2003, three senior executives are entitled to receive a total of $1.5 million in retention bonuses payable in trust units based on the market price at the time of issue, payable in equal semi-annual payments over the next two years subject to certain conditions.

13. Contingencies

The Trust is party to various outstanding claims arising from the normal course of business. In management's opinion, none of the claims, either individually or in total, is expected to have a material impact on the Trust's operations or financial position.

14. Subsequent Events

On January 28, 2004 the Trust closed a financing for $57.5 million and utilized $36.0 million of these funds for the purchase of the Wapella property in Southeast Saskatchewan. The remainder of the financing was used to pay down bank debt.

On February 26, 2004 the Trust purchased Java Energy Inc., a private oil and gas company, for total consideration of approximately $21.8 million including the assumption of $8.0 million in net debt and the issuance of 1.5 million exchangeable shares of the Company at $9 per share.

DIRECTORS AND OFFICERS

RONALD A. MCINTOSH, *Chairman of the Board* — Previously, President and Chief Executive Officer of Navigo since 2001. Before joining Navigo, Mr. McIntosh was Senior Vice President and Chief Operating Officer of Gulf Canada since December 1, 2000. Before joining Gulf Canada Resources Inc., Mr. McIntosh was the Vice President International and Exploration at Petro-Canada Prior thereto, Mr. McIntosh was the Executive Vice President and Chief Operating Officer at Amerada Hess Canada.

THOMAS P. STAN, *President & Chief Executive Officer* — Previously, Vice President and Chief Financial Officer of Navigo since May, 2002. Before joining Navigo, Mr. Stan was the Chairman and Chief Executive Officer of Total Energy Services Ltd. Prior thereto, he was the Vice President, Corporate Development and Strategic Management of Petro-Canada and Vice President, Corporate Planning at Amerada Hess Canada.

JOHN A. BRUSSA, *Director* — Mr. Brussa is a senior tax partner at Burnet, Duckworth and Palmer, a Calgary based law firm.

JAMES W. DAVIE, *Director* — Retired businessman since June 30, 2000. Previously he was Vice President of RBC Dominion Securities Inc.

JOHANNES (JIM) NIEUWENBURG, *Director* — Independent businessman. Prior to June 2001, President and Chief Executive Officer of Petromet Resources Limited and prior to May 1998, Executive Vice President and Chief Operating Officer thereof. Prior to March 1998, Vice President, Asset Management of Norcen Energy Resources Limited. Previously, General Manager, Business Development of Amoco Energy Group, North America.

RODGER TOURIGNY, *Director* — President of Tourigny Management Ltd. (a private management and oil and gas company).

JANALEE F. SHUTIAK, *Vice President & Chief Financial Officer* — Previously, Controller of Navigo since February, 2003. Prior thereto Manager of Financial Accounting and Taxation of Navigo since February, 2002. From 1998 to 2001 Account Executive with Robert Half International. From 1994 to 1998, Treasurer of KB Resources Inc.

RON P. BARMBY, *Vice President, Production & Chief Operating Officer* — Previously, Vice President, Production and Engineering of Navigo since December 2001.Previously, Mr. Barmby was Vice President of Gulfstream Resources from 1995 to 2001. Prior thereto Drilling and Completions Manager and Production Manager with Amerada Hess Canada.

ROB D'ADAMO, *Vice President, Business Development & Land* — Previously, Vice President, Business Development & Land of Navigo since November, 2003. Previously, Manager, Land Negotiations for Petro-Canada since February, 1998. Prior thereto, Senior Land Negotiator at Ulster Petroleum from 1996 to 1997. From 1994, Exploration Coordinator at Amerada Hess Canada.

SHANNON M. GANGL, *Corporate Secretary* — Partner, Burnet, Duckworth & Palmer LLP, since January 1999; prior thereto, Associate, Burnet, Duckworth & Palmer LLP.

CORPORATE INFORMATION

Directors

John A. Brussa [3]
Partner, Burnet, Duckworth and Palmer LLP

James W. Davie [1,3]
Independent Businessman

Ronald A. McIntosh [2]
Chairman of the Board

Johannes (Jim) Nieuwenburg [1,2]
Independent Businessman

Thomas P. Stan
President & Chief Executive Officer

Rodger Tourigny [1,2,3]
President, Tourigny Management Ltd.

(1) Audit Committee
(2) Reserves Committee
(3) Compensation and Governance Committee

Officers

Thomas P. Stan
President & Chief Executive Officer

Ron P. Barmby
Vice President, Production & Chief Operating Officer

Rob D'Adamo
Vice President, Business Development & Land

Janalee F. Shutiak
Vice President & Chief Financial Officer

Auditors

Deloitte and Touche LLP

Banker

National Bank of Canada

Legal Counsel

Burnet, Duckworth and Palmer LLP

Reserves Engineers

Gilbert Laustsen Jung Associates Ltd.

Transfer Agent and Registrar

Computershare Investor Services

Share Listing

Toronto Stock Exchange
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Abbreviations

API	American Petroleum Institute
bbls	barrels
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrel of oil equivalent converting six mcf of natural gas to one barrel of oil
Gj	gigajoule
mbbls	thousand barrels
mboe	thousand barrels of oil equivalent
mmboe	million barrels of oil equivalent
mmbtu	million British thermal units
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet

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